Results, Trends, and Insights from the Accident Sequence Precursor Program

This enclosure discusses the results of accident sequence precursor (ASP) analyses conducted by the U.S. Nuclear Regulatory Commission (NRC), as they relate to events that occurred during Fiscal Years (FY) 2004–2006. Based on those results, this document also discusses the NRC's analysis of historical ASP trends, and the evaluation of the related insights. The seven tables and nine figures that augment this discussion appear at the end of this enclosure.

1.0 ASP Event Analyses

Table 1 summarizes the status of the NRC's ASP analyses, as of September 30, 2006. Specifically, the table identifies ASP analyses that the NRC staff has completed for events that occurred during FY 2004–2006. (Note that, as of September 30, 2006, the staff had not yet screened all of the FY 2006 events.) The following subsections summarize the results of these analyses, which are further detailed in the associated Tables 1–7.

FY 2004 analyses. The ASP analyses for FY 2004 identified 17 precursors. Of the 17 precursors, 14 occurred while the plants were at power.

Table 2 presents the results of the staff's ASP analyses for FY 2004 precursors that involved initiating events, while Table 3 presents the analysis results for precursors that involved degraded conditions.

FY 2005 analyses. The ASP analyses for FY 2005 identified 15 precursors. Of the 15 precursors, 13 occurred while the plants were at power.

Table 4 presents the results of the staff's ASP analyses for FY 2005 precursors that involved initiating events, while Table 5 presents the analysis results for precursors that involved degraded conditions.

FY 2006 analyses. The staff has completed all screening and reviews for potential *significant* precursors (i.e., conditional core damage probability (CCDP) or increase in core damage probability (ΔCDP) $\geq 1\times10^{-3}$) through September 30, 2006. In particular, the staff reviewed a combination of licensee event reports (LERs) (as required by Title 10, Section 50.73, of the *Code of Federal Regulations*) and daily event notification reports (as required by Title 10, Section 50.72, of the *Code of Federal Regulations*) to identify potential *significant* precursors. The staff is still screening and reviewing LERs concerning other potential precursor events that occurred during FY 2006.[1] The goal is to complete preliminary assessments of all FY 2006 events by April 2007.

2.0 Industry Trends

This section discusses the results of trending analyses for all precursors and *significant* precursors.

Statistically significant trend. The trending method used in this analysis is consistent with those methods used in the staff's risk studies. (See Appendix E of Reference 1.) The trending method uses the p-value approach for determining the probability of observing a trend as a result of chance alone. A trend is considered statistically significant if the p-value is smaller than 0.05. The figures at the end of this enclosure show the p-value for each trend.

Data coverage. Most of the data used in the trending analyses span the period from FY 1996 through FY 2005. The trends include the results of both final and preliminary analyses of potential precursors. However, the following exception applies to the data coverage of the trending analyses:

- *Significant precursors.* The trend of *significant* precursors includes events that occurred during FY 2006. The results for FY 2006 are based on the staff's screening and review of a combination of LERs and daily event notification reports.[2] The staff analyzes all potential *significant* precursors immediately.

Precursor trend evaluation. Last year's status report (SECY-05-0192) documented an investigation into the apparent low number of

[1] Licensees have a 60-day grace period after an event or discovery of a degraded condition to submit an LER.

[2] The staff has completed all screening and reviews through September 30, 2006.

precursors during FY 1997–1999 and the subsequent increase in FY 2000–2004. The main conclusions of that investigation were that ASP Program changes (e.g., inclusion of Reactor Oversight Process findings and inclusion of external initiated events) that occurred in FY 2001 significantly increased the number of precursors identified compared to those identified in previous years. In addition, recent groups of outlier events (e.g., the 2003 northeast U.S. electrical blackout resulting in 8 precursor events, the 11 control rod drive mechanism (CRDM) housing cracking conditions between FY 2000 and FY 2003) and the high number of loss of offsite power (LOOP) events that occurred in FY 2003 and FY 2004 were significant contributors to increasing trends.

The staff did not redo work performed as part of last year's analysis as part of this year's analysis. Instead, five-year trend analyses were performed for FY 1996–2000 and FY 2001–2005 periods for groups of precursor affected by the increase in ASP scope (i.e., precursors that involve degraded conditions) that occurred in FY 2001. For the precursor groups not affected by the increase in ASP scope (e.g., precursors involving initiating events), 10-year trend analyses were performed. Performing the trend analyses in this manner more accurately reflect precursor trends over a period when the analyses of events were consistently completed.

2.1 Occurrence Rate of All Precursors

The NRC's Industry Trends Program (ITP) provides the basis for addressing the agency's performance goal measure on the number of "statistically significant adverse industry trends in safety performance" (one measure associated with the safety goal established in the NRC's Strategic Plan). Precursors identified by the ASP Program are one indicator used by the ITP to assess industry performance.

Results. Figure 1 depicts the occurrence rate for all precursors by fiscal year during FY 1996–2000 and FY 2001–2005 periods. A review of the data for that period reveals the following insights:

- The analysis divided the data from FY 1996 through FY 2005 into two parts, FY 1996–2000 and FY 2001–2005, because of the ASP Program scope increased (e.g., inclusion of external events and significance determination process (SDP) findings) in FY 2000. These increases in scope have resulted in the identification of an increasing number of lower risk precursors (i.e., CCDP or ΔCDP $<10^{-4}$). The analysis identified no trend for either of these 5-year periods. The mean rate of occurrence of all precursors in the time period from FY 2001–2005 is higher than what is observed during FY 1996 through FY 2000. In addition to the increases in ASP Program scope, the increased number of outlier events (e.g., the 11 grid-related LOOP events in FY 2003 and FY 2004 and the 11 CRDM housing cracking events between FY 2001 and FY 2003) accounts for the observed change.

- Over the more recent time period from FY 2001–2005, the analysis detected a statistically significant decreasing trend for higher risk precursors (i.e., CCDP or ΔCDP $\geq 10^{-4}$).

2.2 Significant Precursors

The ASP Program provides the basis for the FY 2006 performance goal measure of "zero events per year identified as a *significant* precursor of a nuclear accident" (one measure associated with the safety goal established in the NRC's Strategic Plan).[3] Specifically, the Strategic Plan defines a *significant* precursor as an event that has a probability of at least 1 in 1000 ($\geq 10^{-3}$) of leading to a reactor accident (see Reference 2).

Table 6 summarizes all *significant* precursors that occurred from FY 1969 through FY 2006.

Results. Figure 2 depicts the number of *significant* precursors that occurred during FY 1996–2006. A review of the data for that period reveals the following insights:

- There were no *significant* precursors identified in FY 2006.

- The staff does not detect any statistically significant trend in the occurrence of *significant* precursors during FY 1996–2006. In addition, the analysis revealed no trend for *significant* precursors during the FY 2001–2006 period.

- Over the past 20 years, *significant* precursors have occurred, on average, about once every 4 years. The events in this group involve differing

---

[3] Before FY 2005, the performance goal measure for *significant* precursors was "no more than one event per year identified as a *significant* precursor of a nuclear accident."

failure modes, causes, and systems.

3.0 Insights and Other Trends

The following sections provide additional ASP trends and insights from the period FY 1996 through FY 2005.

3.1 Initiating Events vs. Degraded Conditions

A precursor can be the result of either (1) an operational event involving an initiating event such as a LOOP, or (2) a degraded condition found during a test, inspection, or engineering evaluation. A degraded condition involves a reduction in safety system reliability or function for a specific duration (although no reactor trip initiator actually occurred during this time that challenged the degraded condition).

A review of the data for FY 1996–2005 yields insights described below.

Initiating events

- Over the past 10 years, precursors involving degraded conditions outnumbered initiating events (69 percent compared to 31 percent, respectively). This predominance was most notable in FY 2001 and FY 2002, when degraded conditions contributed to 91 percent and 100 percent of the identified precursors, respectively.

- The mean occurrence rate of precursors involving initiating events exhibits an increasing trend that is statistically significant for the period from FY 1996 through FY 2005, as shown in Figure 3. Specifically, the occurrence rate of such precursors increased over this period by a factor of 3. The analysis detected no trend when the 2003 northeast blackout events are excluded from the data.

- Of the precursors involving initiating events during FY 1996–2005,64 percent are LOOP events. During the period from FY 2001 through FY 2005, 70 percent of all initiating event precursors involved a LOOP.

Degraded conditions

- The analysis divided the data from FY 1996 through FY 2005 into two parts, FY 1996–2000 and FY 2001–2005, because of the ASP Program scope increased (e.g., inclusion of external events and SDP findings) in FY 2000. The mean occurrence rate of precursors involving degraded conditions exhibits a statistically significant decreasing trend during the FY 2001–2005 period, as shown in Figure 4. The analysis detected no trend for the FY 1996–2000 period.

- From FY 1996 through FY 2005, approximately one-half of the precursors involving degraded conditions had a condition start date before FY 1996.

3.2 Precursors Caused by Degraded Conditions

Most precursors involving degraded conditions result from equipment unavailabilities. Such events typically occur for extended periods without a reactor trip, or in combination with a reactor trip in which a risk-important component is unable to perform its safety function as a result of a degraded condition.

A review of the data for FY 1996–2005 yields insights described below concerning the unavailability of safety-related equipment.[4]

Equipment unavailabilities at boiling-water reactors

- Of the 16 precursors involving the unavailability of safety-related equipment that occurred at boiling-water reactors (BWRs) during FY 1996–2005, most were caused by failures in the emergency power system (69 percent), residual heat removal system (31 percent), or high-pressure coolant injection system (13 percent).

Emergency core cooling systems in pressurized-water reactors

- The unavailability of safety-related high- and/or low-pressure injection trains contributed to 61 percent of all identified precursors that occurred at pressurized-water reactors (PWRs) during FY 1996–2005. Failures in either the emergency core cooling system (ECCS) (22 percent) or emergency power sources (18 percent) caused most of these unavailabilities, or they resulted from design-basis issues involving other structures or systems that impact either the

[4] The sum of percentages presented in this section does not always equal 100 percent because some precursors involve multiple equipment unavailabilities.

ECCS or one of its support systems (51 percent).

- A condition that affected sump recirculation during postulated loss-of-coolant accidents (LOCAs) of varying break sizes caused 25 of the precursors.

Auxiliary/emergency feedwater systems in PWRs

- The unavailability of one or more trains of the auxiliary and emergency feedwater (AFW/EFW) systems contributed to 39 percent of all precursors that occurred at PWRs. Most of these unavailabilities were the result of failures in the AFW/EFW systems (16 percent) or emergency power sources (35 percent), or they resulted from design-basis issues involving other structures or systems that impact either the AFW/EFW systems or one of their support systems (49 percent).

- The seven precursors that involved a failure in an AFW/EFW train yield the following insights:

  - Two of the train failures occurred following a reactor trip.

  - All seven of the precursors involved the unavailability of the turbine-driven AFW/EFW pump train.

Emergency power sources in PWRs

- The unavailability of emergency power sources such as emergency diesel generators (EDGs) and hydroelectric generators (at Oconee), contributed to 23 percent of all precursors that occurred at PWRs.[5] Most of these unavailabilities resulted from random hardware failures in the emergency power system (44 percent).

- The other unavailabilities were attributable to design-basis issues (36 percent) and losses of service water (20 percent).

- In all the analyzed LOOP events at PWRs, the turbine-driven AFW/EFW pumps were operable.

Section 3.3 discusses insights related to precursors that involved a LOOP with simultaneous EDG unavailability.

3.3 Precursors Involving LOOP Initiating Events

Six LOOP events occurred during FY 2004, while only one LOOP event occurred during 2005. The FY 2005 LOOP event occurred at Waterford, while the plant was shut down, and was caused by the effects of Hurricane Katrina.

Results. A review of the data for FY 1996–2005 leads to the following insights:

- The mean occurrence rate of precursors resulting from a LOOP does not exhibit a trend that is statistically significant for the period from FY 1996 through FY 2005, as shown in Figure 5. It is noted that the number of LOOP events in 2003 and 2004 is much higher than in previous years. The NRC has implemented initiatives to address this increase.

- Of the LOOP precursor events that occurred during FY 1996–2005, 11 percent had a CCDP $\geq 1\times10^{-4}$.

- A simultaneous unavailability of an emergency power system train was involved in 4 of the 27 LOOP precursor events during FY 1996–2005. One of these precursors was a *significant* precursor (Catawba Unit 2, 1996).

3.4 Precursors at BWRs vs. PWRs

Since FY 2001, 25 precursors have occurred at BWRs, which is 22 more than the total from the previous 5 years. Over the past 10 years, 109 precursors have occurred at PWRs, with approximately 60 percent occurring in the past 5 years.

A review of the data for FY 1996–2005 reveals the results for BWRs and PWRs described below.

BWRs

- The analysis divided the data from FY 1996 through FY 2005 into two parts, FY 1996–2000 and FY 2001–2005, because of the ASP Program scope increased (e.g., inclusion of external events and SDP findings) in FY 2000.

---

[5] Not all EDG unavailabilities are precursors. The ASP Program screens out an EDG unavailability for a period of less than one surveillance test cycle (1 month) is screened out in the ASP Program (assuming no other complications). In addition, the risk contributions of EDG unavailabilities vary from plant-to-plant and may result in a ΔCDP less than the threshold of a precursor (1×10^{-6}).

The analysis identified no trend for either of these 5-year periods, as shown in Figure 6. The mean rate of occurrence of precursors occurring at BWRs in the time period from FY 2001–2005 is higher than what is observed during FY 1996 through FY 2000. In addition to the increase in ASP Program scope, the large number of LOOP events that occurred at BWRs in FY 2003 account for the observed change.

- An average of three precursors per year occurred at BWRs during the FY 1996–2005 period.

- LOOP events contributed to 60 percent of precursors involving initiating events at BWRs.

- Only three precursors occurred at a BWR during the 5-year period from FY 1996 through FY 2000.

PWRs

- The analysis divided the data from FY 1996 through FY 2005 into two parts, FY 1996–2000 and FY 2001–2005, because of the ASP Program scope increased (e.g., inclusion of external events and SDP findings) in FY 2000. The analysis identified no trend for either of these 5-year periods, as shown in Figure 7. The mean rate of occurrence of precursors occurring at PWRs in the time period from FY 2001–2005 is higher than what is observed during FY 1996 through FY 2000. In addition to the increases in ASP Program scope, the increased number of outlier events (e.g., the 6 grid-related LOOP events in FY 2003 and FY 2004 and the 11 CRDM housing cracking events between FY 2001 and FY 2003) accounts for the observed change.

- An average of 11 precursors per year occurred at PWRs during FY 1996–2005.

- LOOP events contribute to 69 percent of precursors involving initiating events at PWRs.

3.5 Integrated ASP Index

The staff derives the integrated ASP index for order-of-magnitude comparisons with industry-average core damage frequency (CDF) estimates derived from probabilistic risk assessments (PRAs) and the NRC's Standardized Plant Analysis Risk (SPAR) models. The index or CDF from precursors for a given fiscal year is the sum of CCDPs and ΔCDPs in the fiscal year divided by the number of reactor-calendar years in the fiscal year.

The integrated ASP index, includes the risk contribution of a precursor for the entire duration of the degraded condition (i.e., the risk contribution is included in each fiscal year that the condition exists). The risk contributions from precursors involving initiating events are included in the fiscal year that the event occurred.

Examples. A precursor involving a degraded condition is identified in FY 2003 and has a ΔCDP of 5×10^{-6}. A review of the LER reveals that the degraded condition has existed since a design modification performed in FY 2001. In the integrated ASP index, the ΔCDP of 5×10^{-6} is included in the FYs 2001, 2002, and 2003.

For an initiating event occurring in FY 2003, the CCDP from this precursor is included only in FY 2003.

Results. Figure 8 depicts the integrated ASP indices for FY 1996–2005. A review of the ASP indices leads to the following insights:

- Based on order of magnitude, the average integrated ASP index for the period from FY 1996 through FY 2005 is consistent with the CDF estimates from the SPAR models and the licensees' PRAs.

- The risk contribution from precursors is generally constant over this time period and has decreased since FY 2003.

- Contributions to the average integrated CDF from precursors over the 10-year period (FY 1996–2005) are as follows:

  - Four precursors contribute to nearly one-half (43 percent) of the average integrated CDF from precursors over the 10-year period. Specifically, long-term degraded conditions at Point Beach Units 1 and 2 (discovered in 2001) involved potential common-mode failure of all AFW pumps, while long-term degraded conditions at D.C. Cook Units 1 and 2 (discovered in 1999) involved a number of locations in the plant where the effects of postulated high-energy line break events would damage safety-related components. The associated ΔCDPs of the degraded conditions at Point Beach and D.C. Cook were high (7×10^{-4} and 4×10^{-4}, respectively) and the degraded conditions had existed since plant construction.

– Two *significant* precursors (i.e., CCDP or ΔCDP $\geq 1\times10^{-3}$) contribute to 25 percent of the average integrated CDF from precursors over the 10-year period. Each *significant* precursor existed for a 1-year period. Table 6 describes these events.

– The remaining 32 percent of the average integrated CDF from precursors over the 10-year period was from contributions from 131 precursors.

Limitations. Using CCDPs and ΔCDPs from ASP results to estimate CDF is difficult because (1) the mathematical relationship requires a significant level of detail, (2) statistics for frequency of occurrence of specific precursor events are sparse, and (3) the assessment must also account for events and conditions that did not meet the ASP precursor criteria.

The integrated ASP index provides the contribution of risk (per FY) resulting from precursors and cannot be used for direct trending purposes since the discovery of precursors involving longer term degraded conditions in future years may change the cumulative risk from the previous year(s). Because of these and other limitations, the staff has primarily used the rate of CCDPs and ΔCDPs as a trending indication.

3.6 Consistency with PRAs and IPEs

A secondary objective of the ASP Program is to provide a partial validation of the dominant core damage scenarios predicted by PRAs and individual plant examinations (IPEs). Most of the identified precursor events are consistent with failure combinations identified in PRAs and IPEs.

However, a review of the precursor events for FY 1996–2005 reveals that approximately 36 percent of the identified precursors involved event initiators or failure modes that were not explicitly modeled in the PRA or IPE for the specific plant where the precursor event occurred. Table 7 lists these precursors. The occurrence of these precursors does not imply that explicit modeling is needed; however, such modeling could yield insights that could be incorporated in future revisions of the PRA.

3.7 Review of Human Error Contributions

The staff reviewed precursor data from the ASP Program during the FY 2000–2004 period to identify the kinds of human errors that are associated with precursor events. In this updated review, the staff used the classification scheme and approach developed in previous studies (References 3 and 4) of the same subject. In addition, the staff identified and compared human errors associated with select Green inspection findings during FY 2004 the human errors associated with higher risk precursor events. The following summarizes these findings:

- *Number of human errors in precursors.* The average number of errors per precursor was approximately three. Although precursors can involve multiple error events, the CCDP or ΔCDP for these precursors was generally low (in the 10^{-6} to 10^{-5} range), an indication that sufficient redundancy and defense-in-depth remained.

- *Error contributions to precursors.* Figure 9 shows the percentage of precursors with at least one error in a subcategory. When the percentage of precursors with at least one error in the subcategory is considered, the dominant subcategories are inadequate procedures/procedure development (39 percent); design deficiencies (33 percent); inadequate engineering evaluation/review (28 percent); failure to correct known deficiencies (25 percent); inadequate maintenance and testing practices (18 percent); issues with management oversight (15 percent); and incorrect operator action/inaction (14 percent).

- *Higher risk precursors.* The staff reviewed precursors with a CCDP or ΔCDP greater than or equal to 1×10^{-5} to identify the error(s) that contributed most to the overall risk of the initiating event (CCDP) or degraded condition (ΔCDP).

  Of the 30 higher risk precursors, design-related errors caused 35 percent. Errors in the Design and Engineering category contributed to the risk of 9 out of 18 degraded conditions and 2 out of 13 initiating events.

  Of the 13 precursors involving initiating events, 11 had no significant risk contribution from human errors. Most of these events involved a LOOP initiator caused by a fault outside the plant boundary, such as grid-related and hurricane-related LOOP events.

4.0 Summary

This section summarizes the ASP results, trends, and insights.

- ***Significant precursors.*** No *significant* precursors (i.e., CCDP or ΔCDP $\geq 1\times10^{-3}$) were identified in FYs 2005 or 2006. The ASP Program provides the basis for the FY 2005 performance goal measure of "zero events per year identified as a *significant* precursor of a nuclear accident." The NRC's Performance and Accountability Report for FY 2006 and the NRC Performance Budget for FY 2007 will report these results.

- ***Occurrence rate of all precursors.*** The analysis divided the data from FY 1996 through FY 2005 into two parts, FY 1996–2000 and FY 2001–2005, because of the ASP Program scope increased (e.g., inclusion of external events and SDP findings) in FY 2000. These increases in scope have resulted in the identification of an increasing number of lower risk precursors (i.e., CCDP or ΔCDP $<10^{-4}$). The analysis identified no trend for either of these 5-year periods. The mean rate of occurrence of all precursors in the time period from FY 2001–2005 is higher than what is observed during FY 1996 through FY 2000. In addition to the increases in ASP Program scope, the increased number of outlier events (e.g., the 11 grid-related LOOP events in FY 2003 and FY 2004 and the 11 CRDM housing cracking events between FY 2001 and FY 2003) accounts for the observed change.

  Over the more recent time period from FY 2001–2005, the analysis detected a statistically significant decreasing trend for higher risk precursors (i.e., CCDP or ΔCDP $\geq 10^{-4}$).

  The ITP uses this trend as one of the agency's monitored indicators. The NRC's Performance and Accountability Report for FY 2006 and the NRC Performance Budget for FY 2007 will report these results.

5.0 References

1. U.S. Nuclear Regulatory Commission. NUREG/CR-5750, "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987–1995." Washington, DC. February 1999.

2. U.S. Nuclear Regulatory Commission. NUREG-1100, Vol. 21, "Performance Budget, Fiscal Year 2006." Washington, DC. February 2005.

3. U.S. Nuclear Regulatory Commission. NUREG/CR-6753, "Review of Findings for Human Performance Contribution to Risk in Operating Events." Washington DC. August 2001.

4. U.S. Nuclear Regulatory Commission. NUREG/CR-6775, "Human Performance Characterization in the Reactor Oversight Process." Washington, DC. September 2001.

Table 1. Status of ASP analyses (as of September 30, 2006).

Status	FY 2004	FY 2005	FY 2006[a]
Analyzed events that were determined not to be precursors	27	32	2
Events to be further analyzed	--	--	50
ASP precursor analyses	15	7	–[b]
SDP (or MD 8.3) results used for ASP program input	2	8	–[b]
Total precursors identified	17	15	--

a. As of September 30, 2006, the staff has not yet screened all of the FY 2006 events and unavailabilities.
b. Based on historical data, expectations are that approximately 40 percent of ASP precursors will use SDP or MD 8.3 results.

Table 2. FY 2004 precursors involving initiating events (as of September 30, 2006).

Event Date	Plant	Description	CCDP
1/23/04	Calvert Cliffs 2	Reactor trip caused by loss of main feedwater and complicated by a failed relay causing overcooling. ***LER 318/04-001***	2×10^{-6}
5/5/04	Dresden 3	Plant-centered LOOP due to breaker malfunction. ***LER 249/04-003***	3×10^{-6}
6/14/04	Palo Verde 1	Grid-related LOOP with offsite power recovery complications due to breaker failure. ***LER 528/04-006***	9×10^{-6}
6/14/04	Palo Verde 2	Grid-related LOOP with an emergency diesel generator unavailable. ***LER 528/04-006***	4×10^{-5}
6/14/04	Palo Verde 3	Grid-related LOOP with offsite power recovery complications due to breaker failure. ***LER 528/04-006***	9×10^{-6}
9/25/04	St. Lucie 1	Severe weather LOOP caused by Hurricane Jeanne while the plant was shut down. ***LER 335/04-004***	1×10^{-5}
9/25/04	St. Lucie 2	Severe weather LOOP caused by Hurricane Jeanne while the plant was shut down. ***LER 335/04-004***	1×10^{-5}

Table 3. FY 2004 precursors involving degraded conditions (as of September 30, 2006).

Event Date[a]	Condition Duration[b]	Plant	Description	ΔCDP
11/3/03	since plant startup	Surry 1	Potential loss of reactor coolant pump (RCP) seal cooling due to postulated fire damage to emergency switchgear. ***LER 280/03-005***	1×10^{-6}
11/3/03	since plant startup	Surry 2	Potential loss of RCP seal cooling due to postulated fire damage to emergency switchgear. ***LER 280/03-005***	1×10^{-6}
1/4/04	720 hours	Brunswick 2	EDG "3" unavailable due to jacket water leak. ***LER 325/04-001***	2×10^{-6}
2/3/04	since plant startup	Turkey Point 3	Triennial fire protection issues. ***LER 251/04-007***	7×10^{-6}
2/3/04	since plant startup	Turkey Point 4	Triennial fire protection issues. ***LER 251/04-007***	7×10^{-6}
2/19/04	61 hours	Palo Verde 2	Failure to implement design of steam generator nozzle dam requiring an extended time in reduced RCS inventory configuration. ***IR 529/04-04, IR 529/04-09***	1×10^{-5}
3/17/04	1117 hours	Peach Bottom 3	High-pressure coolant injection (HPCI) unavailable due to failed flow controller. ***LER 278/04-001***	2×10^{-6}
7/31/04	11 years[c]	Palo Verde 1	Containment sump recirculation potentially inoperable due to pipe voids. ***LER 528/04-009***	4×10^{-5}
7/31/04	11 years[c]	Palo Verde 2	Containment sump recirculation potentially inoperable due to pipe voids. ***LER 528/04-009***	4×10^{-5}
7/31/04	11 years[c]	Palo Verde 3	Containment sump recirculation potentially inoperable due to pipe voids. ***LER 528/04-009***	4×10^{-5}

a. ASP event date is the discovery date for a precursor involving a degraded condition.
b. Condition duration is the time period when the degraded condition existed. The ASP Program limits the analysis exposure time of degraded condition to 1 year.
c. Exact date not given. LER states that condition had existed since 1992 when the new feedwater control system was installed before the power uprate.

Table 4. FY 2005 precursors involving initiating events (as of September 30, 2006).

Event Date	Plant	Description	CCDP
10/10/04	Hope Creek	Manual reactor scram due to moisture separator reheater drain line failure. ***LER 354/04-010***	3×10^{-6}
11/20/04	Vogtle 2	Reactor trip with safety injection and full-open demand from steam bypass valves caused by operator error and failed circuit card. ***LER 425/04-004***	3×10^{-6}
12/10/04	River Bend	Reactor trip due to loss of a non-vital 120V instrument bus. ***LER 458/04-005***	3×10^{-5}
2/22/05	Watts Bar	Low-temperature, over-pressure valve actuations while shut down. ***IR 390/05-03***	7×10^{-6}
4/17/05	Millstone 3	Inadvertent reactor trip and safety injection with failure of turbine-driven AFW pump to start (recoverable). ***LER 423/05-002***	3×10^{-6}
6/23/05	Columbia	Reactor trip due to feedwater pump trip cause by maintenance personnel error. ***LER 397/05-004***	1×10^{-5}
8/29/05	Waterford	Severe weather LOOP caused by Hurricane Katrina while plant was shut down. ***LER 382/05-004***	2×10^{-6}

Table 5. FY 2005 precursors involving degraded conditions (as of September 30, 2006).

Event Date[a]	Condition Duration[b]	Plant	Description	ΔCDP
10/19/04	682 hours	Fort Calhoun	EDG 2 inoperable for 28 days due to blown fuse. ***LER 285/04-002***	$4{\times}10^{-6}$
11/22/04	6024 hours	Watts Bar	Component cooling backup line from essential raw cooling water unavailable due to silt blockage. ***IR 390/04-05***	$8{\times}10^{-6}$
1/27/05	10 years[c]	Crystal River 3	Single-failure vulnerability of 4160 V engineered safeguard feature (ESF) bus protective relay schemes caused by common power metering circuits. ***LER 302/05-001***	$5{\times}10^{-6}$
2/2/05	13 years[d]	LaSalle 1	Single-failure vulnerability of 4160 V ESF bus protective relay schemes caused by common power metering circuits. ***LER 373/05-001***	$5{\times}10^{-6}$
2/2/05	13 years[d]	LaSalle 2	Single-failure vulnerability of 4160 V ESF bus protective relay schemes caused by common power metering circuits. ***LER 373/05-001***	$5{\times}10^{-6}$
2/11/05	since plant startup	Kewaunee	Several design deficiencies could lead to unavailability of AFW pumps during postulated events (e.g., high-energy line break and tornado). ***LER 305/05-002, LER 305/05-006, LER 305/05-008***	$1{\times}10^{-5}$
4/27/05	17 days	Indian Point 2	Potential degradation of safety injection system due to nitrogen accumulation from leaking accumulator. ***IR 50-247/05-06***	$3{\times}10^{-6}$
5/10/05	since plant startup	Kewaunee	Design deficiency could cause unavailability of safety-related equipment during postulated internal flooding. ***LER 305/05-004***	Yellow[e]

a. ASP event date is the discovery date for a precursor involving a degraded condition.
b. Condition duration is the time period when the degraded condition existed. The ASP Program limits the analysis exposure time of degraded condition to 1 year.
c. Exact date not given. LER states that condition had existed since a 1990 design modification.
d. Conditions had existed since design modifications completed on 03/08/91 for Unit 1 and 02/01/92 for Unit 2.
e. The result presented is the final significance determination under the Reactor Oversight Process. Separately, the licensee's numerical estimate was approximately $8{\times}10^{-5}$. The staff confirmed that this condition meets the ASP Program threshold of a precursor (i.e., ΔCDP $\geq 1{\times}10^{-6}$), but does not exceed the threshold of a *significant* precursor (i.e., ΔCDP $\geq 1{\times}10^{-3}$).

Table 6. *Significant* (CCDP or ΔCDP $\geq 1\times10^{-3}$) accident sequence precursors during the 1969–2005 period in order by event date. *(See notes at the end of table)*

Plant	ΔCDP or CCDP	Date	Description
Davis-Besse	6×10^{-3}	2/27/02	**Multiple conditions coincident with reactor pressure vessel (RPV) head degradation** The analysis included multiple degraded conditions discovered on various dates. These conditions included cracking of CRDM nozzles and RPV head degradation, potential clogging of the emergency sump, and potential degradation of the high-pressure injection (HPI) pumps during recirculation. ***LER 346/02-002***
Catawba 2	2×10^{-3}	2/6/96	**LOOP with an EDG unavailable** When the reactor was at hot shutdown, a transformer in the switchyard shorted out during a storm, causing breakers to open and resulting in a LOOP event. Although both EDGs started, the output breaker of EDG 1B, to essential bus 1B failed to close on demand, leaving bus 1B without AC power. After 2 hours and 25 minutes, operators successfully closed the EDG 1B output breaker. ***LER 414/96-001***
Wolf Creek 1	3×10^{-3}	9/17/94	**Reactor coolant system (RCS) blowdown to refueling water storage tank (RWST)** When the plant was in cold shutdown, operators implemented two unpermitted simultaneous evolutions, which resulted in the transfer of 9,200 gallons (34,825 liters) of RCS inventory to the RWST. Operators immediately diagnosed the problem and terminated the event by closing the residual heat removal (RHR) cross-connect motor-operated valve. The temperature of the RCS increased by 7 °F (4 °C) as a result of this event. ***LER 482/94-013***
Harris 1	6×10^{-3}	4/3/91	**HPI unavailability for one refueling cycle** A degraded condition resulted from relief valve and drain line failures in the alternative minimum flow systems for the charging/safety injection pumps, which would have diverted a significant amount of safety injection flow away from the reactor coolant system. The root cause of the degradation is believed to have been water hammer, as a result of air left in the alternative minimum flow system following system maintenance and test activities. ***LER 400/91-008***
Turkey Point 3	1×10^{-3}	12/27/86	**Turbine load loss with trip; control rod drive (CRD) auto insert fails; manual reactor trip; power-operated relief valve (PORV) sticks open** The reactor was tripped manually following a loss of turbine governor oil system pressure and the subsequent rapid electrical load decrease. Control rods failed to insert automatically because of two cold solder joints in the power mismatch circuit. During the transient, a PORV opened but failed to close (the block valve had to be closed). The loss of governor oil pressure was the result of a cleared orifice blockage and the auxiliary governor dumping control oil. ***LER 250/86-039***

Plant	ΔCDP or CCDP	Date	Description
Catawba 1	3×10^{-3}	6/13/86	**Chemical and volume control system (CVCS) leak (130 gpm) from the component cooling water (CCW)/CVCS heat exchanger joint (i.e., small-break loss-of-coolant accident (LOCA))** A weld break on the letdown piping, near the CCW/CVCS heat exchanger caused excessive RCS leakage. A loss of motor control center power caused the variable letdown orifice to fail open. The weld on the 1-inch (2.54-cm) outlet flange on the variable letdown orifice failed as a result of excessive cavitation-induced vibration. This event was a small-break LOCA. ***LER 413/86-031***
Davis-Besse	1×10^{-2}	6/9/85	**Loss of feedwater; scram; operator error fails AFW; PORV fails open** While at 90-percent power, the reactor tripped with main feedwater (MFW) pump 1 tripped and MFW pump 2 unavailable. Operators made an error in initiating the steam and feedwater rupture control system and isolated EFW to both steam generators (SGs). The PORV actuated three times and did not reseat at the proper RCS pressure. Operators closed the PORV block valves, recovered EFW locally, and used HPI pump 1 to reduce RCS pressure. ***LER 346/85-013***
Hatch 1	2×10^{-3}	5/15/85	**Heating, ventilation, and air conditioning (HVAC) water shorts panel; safety relief valve (SRV) fails open; HPCI fails; reactor core isolation cooling (RCIC) unavailable** Water from an HVAC vent fell onto an analog transmitter trip system panel in the control room (the water was from the control room HVAC filter deluge system which had been inadvertently activated as a result of unrelated maintenance activities). This resulted in the lifting of the SRV four times. The SRV stuck open on the fourth cycle, initiating a transient. Moisture also energized the HPCI trip solenoid making HPCI inoperable. RCIC was unavailable due to maintenance. ***LER 321/85-018***
Lasalle 1	2×10^{-3}	9/21/84	**Operator error causes scram; RCIC unavailable; RHR unavailable** While at 23-percent power, an operator error caused a reactor scram and main steam isolation valve (MSIV) closure. RCIC was found to be unavailable during testing (one RCIC pump was isolated, and the other pump tripped during the test). RHR was found to be unavailable during testing because of an inboard suction isolation valve failing to open on demand. Both RHR and RCIC may have been unavailable after the reactor scram. ***LER 373/84-054***
Salem 1	5×10^{-3}	2/25/83	**Trip with automatic reactor trip capability failed** When the reactor was at 25-percent power, both reactor trip breakers failed to open on demand of a low-low SG level trip signal. A manual trip was initiated approximately 3 seconds after the automatic trip breaker failed to open, and was successful. The same event occurred 3 days later, at 12-percent power. Mechanical binding of the latch mechanism in the breaker under-voltage trip attachment failed both breakers in both events. ***LER 272/83-011***

Plant	ΔCDP or CCDP	Date	Description
Davis-Besse	2×10^{-3}	6/24/81	**Loss of vital bus; failure of an EFW pump; main steam safety valve lifted and failed to reseat** With the plant at 74-percent power, the loss of bus E2 occurred because of a maintenance error during CRDM breaker logic testing. A reactor trip occurred, due to loss of CRDM power (bus E2), and instrumentation power was also lost (bus E2 and a defective logic card on the alternate source). During the recovery, EFW pump 2 failed to start because of a maladjusted governor slip clutch and bent low speed stop pin. A main steam safety valve lifted, and failed to reseat (valve was then gagged). ***LER 346/81-037***
Brunswick 1	7×10^{-3}	4/19/81	**RHR heat exchanger damaged** While the reactor was in cold shutdown during a maintenance outage, the normal decay heat removal system was lost because of a failure of the single RHR heat exchanger that was currently in service. The failure occurred when the starting of a second RHR service water pump caused the failure of a baffle in the waterbox of the RHR heat exchanger, thereby allowing cooling water to bypass the tube bundle. The redundant heat exchanger was inoperable because maintenance was in progress. ***LER 325/81-032***
Millstone 2	5×10^{-3}	1/2/81	**Loss of DC power and one EDG as a result of operator error; partial LOOP** When the reactor was at full power, the 125 V DC emergency bus was lost as a result of operator error. The loss of the bus caused the reactor to trip, but the turbine failed to trip because of the unavailability of DC bus A. Loads were not switched to the reserve transformer (following the manual turbine trip) because of the loss of DC bus A. Two breakers (on the B 6.9 kV and 4.16 kV busses) remained open, thereby causing a LOOP. EDG B tripped as a result of leakage of the service water flange, which also caused the B 4.16 kV bus to be de-energized. An operator recognition error caused the PORV to be opened at 2380 psia. ***LER 336/81-005***
St. Lucie 1	1×10^{-3}	6/11/80	**Reactor coolant pump seal LOCA due to loss of CCW; top vessel head bubble** At 100-percent power, a moisture-induced short circuit in a solenoid valve caused a CCW containment isolation valve to shut causing loss of CCW to all RCPs. While pressure was reduced to initiate the shutdown cooling system (SCS), the top head water flashed to steam, thus forming a bubble (initially undetected by the operators). During the cooldown, the SCS relief valves lifted and low-pressure safety injection (LPSI) initiated (i.e., one LPSI pump started charging, while the other was used for cooldown). ***LER 335/80-029***
Davis-Besse	1×10^{-3}	4/19/80	**Loss of two essential busses** When the reactor was in cold shutdown, two essential busses were lost because of breaker ground fault relay actuation during an electrical lineup. The decay heat drop line valve was shut, and air was drawn into the suction of the decay heat removal pumps, resulting in loss of a decay heat removal path. ***LER 346/80-029***

Plant	ΔCDP or CCDP	Date	Description
Crystal River 3	5×10^{-3}	2/26/80	**Loss of 24-V DC power to non-nuclear instrumentation (NNI)** The 24-V power supply to the NNI was lost as a result of a short to ground. This initiated a sequence of events in which the PORV opened (and stayed open) as a direct result of the loss of the NNI power supply. HPI initiated as a result of depressurization through the open PORV, and with approximately 70 percent of NNI inoperable or inaccurate, the operator correctly decided that there was insufficient information available to justify terminating HPI. Therefore, the pressurizer was pumped solid, one safety valve lifted, and flow through the safety valve was sufficient to rupture the reactor coolant drain tank rupture disk, thereby spilling approximately 43,000 gallons (162,800 liters) of primary water into the containment. ***LER 302/80-010***
Hatch 2	1×10^{-3}	6/3/79	**Loss of feedwater; HPCI fails to start; RCIC is unavailable** During a power increase, the reactor tripped because a condensate system trip. HPCI failed to initiate on low-low level due to a failed turbine stop valve. In addition, water from leaking mechanical seal lines and an unknown valve caused water to back up and contaminate the pump oil. RCIC was out of service for unspecified reasons. ***LER 366/79-045***
Oyster Creek	2×10^{-3}	5/2/79	**Loss of feedwater flow** During testing of the isolation condenser, a reactor scram occurred. The feedwater pump tripped and failed to restart. The recirculation pump inlet valves were closed. The isolation condenser was used during cooldown. ***LER 219/79-014***
Three Mile Island 2	1	3/28/79	**Loss of feedwater; PORV failed open; operator errors led to core damage** Operators misinterpreted plant conditions, including the RCS inventory, during a transient that was triggered by a loss of feedwater and a stuck-open PORV. As a result, the operators prematurely shut off the high-pressure safety injection system, turned off the reactor coolant pumps, and failed to diagnose and isolate a stuck-open pressurizer relief valve. With no RCS inventory makeup, the core became uncovered and fuel damage occurred. In addition, contaminated water was spilled into the containment and auxiliary buildings. ***LER 320/79-012***
Salem 1	1×10^{-2}	11/27/78	**Loss of vital bus and scram; multiple components lost** While the reactor was at 100-percent power, vital instrument bus 1B was lost as a result of the failure of an output transformer and two regulating resistors. Loss of the vital bus caused a false low RCS loop flow signal, thereby causing a reactor trip. Two EFW pumps failed to start (one because of the loss of vital bus 1B, and the other because of a maladjustment of the over-speed trip mechanism). Inadvertent safety injection occurred as a result of decreasing average coolant temperature and safety injection signals. ***LER 272/78-073***
Calvert Cliffs 1	3×10^{-3}	4/13/78	**LOOP; one EDG failed to start** With the plant shut down, a protective relay automatically opened the switchyard breakers, resulting in a LOOP. EDG 11 failed to start. EDG 22 started and supplied the safety busses. ***LER 317/78-020***

Plant	ΔCDP or CCDP	Date	Description
Farley 1	5×10^{-3}	3/25/78	**Low-Low water level in one SG trip/scram; turbine-driven EFW pump fails** A low-level condition in a single SG resulted in a reactor trip. The turbine-driven EFW pump failed to start. Both motor-driven EFW pumps started, but were deemed ineffective because all recirculation bypass valves were open (thereby diverting flow). A recirculation valve was manually closed. ***LER 348/78-021***
Rancho Seco	1×10^{-1}	3/20/78	**Failure of NNI and steam generator dryout** When the reactor was at power, a failure of the NNI power supply resulted in a loss of main feedwater, which caused a reactor trip. Because instrumentation drift falsely indicated that the steam generator contained enough water, control room operators did not act promptly to open the EFW flow control valves to establish secondary heat removal. This resulted in steam generator dryout. ***LER 312/78-001***
Davis-Besse	5×10^{-3}	12/11/77	**EFW pumps inoperable during test** During EFW pump testing, operators found that control over both pumps was lost because of mechanical binding in the governor of one pump and blown control power supply fuses for the speed changer motor on the other pump. ***LER 346/77-110***
Davis-Besse	7×10^{-2}	9/24/77	**Stuck-open pressurizer PORV** A spurious half-trip of the steam and feedwater rupture control system initiated closure of the startup feedwater valve. This resulted in reduced water level in SG 2. The pressurizer PORV lifted nine times and then stuck open because of rapid cycling. ***LER 346/77-016***
Cooper	1×10^{-3}	8/31/77	**Partial loss of feedwater; reactor scram; RCIC and HPCI degraded** A blown fuse caused the normal power supply to the feedwater and RCIC controllers to fail. The alternate power supply was unavailable because of an unrelated fault. A partial loss of feedwater occurred, and the reactor tripped on low water level. RCIC and HPCI operated, however, both pumps did not accelerate to full speed (RCIC because of the failed power supply and HPCI because of a failed governor actuator). ***LER 298/77-040***
Zion 2	2×10^{-3}	7/12/77	**Testing causes instrumentation errors** With the reactor in hot shutdown, testing caused operators to lose indications of reactor and secondary system parameters. In addition, inaccurate inputs were provided to control and protection systems. ***LER 304/77-044***
Millstone 2	1×10^{-2}	7/20/76	**LOOP from grid disturbance; errors in EDG loading fail the ECCS** With the reactor at power, a main circulating water pump was started, which resulted in an in-plant voltage reduction to below the revised trip set point. This isolated the safety-related busses and started the EDGs. Each time a major load was tied onto the diesel, the revised under-voltage trip set points tripped the load. As a result, at the end of the EDG loading sequence, all major loads were isolated, even though the EDGs were tied to the safety-related busses. ***LER 336/76-042***

Plant	ΔCDP or CCDP	Date	Description
Kewaunee	5×10^{-3}	11/5/75	**Inoperable EFW pumps during startup as a result of leaks from the demineralizer into the condensate storage tank (CST)** Mixed bed resin beads were leaking from the demineralizer in the makeup water system and migrated to the CST. As a result, during startup, both motor-driven EFW pump suction strainers became clogged, thereby resulting in low pump flow. The same condition occurred for the turbine-driven EFW pump suction strainer. ***LER 305/75-020***
Brunswick 2	9×10^{-3}	4/29/75	**Multiple valve failures; RCIC inoperable as a result of stuck-open down/safety valve** At 10-percent power, the RCIC system was determined to be inoperable, and SRV B was stuck open. The operator failed to scram the reactor according to the emergency operating procedures (EOPs). The HPCI system failed to run and was manually shut down as a result of high torus level. Loop B of RHR failed as a result of a failed service water supply valve to the heat exchanger. The reactor experienced an automatic scram on manual closure of the MSIV. ***LER 324/75-013***
Browns Ferry 1	2×10^{-1}	3/22/75	**Cable tray fire** The fire was started by an engineer, who was using a candle to check for air leaks through a firewall penetration seal to the reactor building. The fire resulted in significant damage to cables related to the control of Units 1 and 2. All Unit 1 ECCS were lost, as was the capability to monitor core power. Unit 1 was manually shut down and cooled using remote manual relief valve operation, the condensate booster pump, and control rod drive system pumps. Unit 2 was shut down and cooled for the first hour by the RCIC system. After depressurization, Unit 2 was placed in the RHR shutdown cooling mode with makeup water available from the condensate booster pump and control rod drive system pump. ***LER 259/75-006***
Turkey Point 3	2×10^{-2}	5/8/74	**Failure of three EFW pumps to start during test** Operators attempted to start all three EFW pumps while the reactor was at power for testing. Two of the pumps failed to start as a result of over-tightened packing. The third pump failed to start because of a malfunction in the turbine regulating valve pneumatic controller. ***LER 250/74-LTR***
Point Beach 1	5×10^{-3}	4/7/74	**Inoperable EFW pumps during shutdown** While the reactor was in cooldown mode, motor-driven EFW pump A did not provide adequate flow. The operators were unaware that the in-line suction strainers were 95 percent plugged (both motor-driven pumps A and B). A partially plugged strainer was found in each of the suction lines for both turbine-driven EFW pumps. ***LER 266/74-LTR***
Point Beach 1	1×10^{-3}	1/12/71	**Failure of containment sump valves** During a routine check of the containment tendon access gallery, air was observed leaking from the packing of one sump isolation valve. Operators attempted to open the valve, but the valve failed to open because of a shorted solenoid in the hydraulic positioner. The redundant sump isolation valve was also found inoperable because of a stuck solenoid in the hydraulic positioner. ***LER 266/71-LTR***

NOTES:

- Events are selected on the basis of CCDPs, as estimated by the ASP Program.
- Because of model and data uncertainties, it is difficult to differentiate between events with CCDPs that are within a factor of about 3.
- ASP analyses have been performed since 1969, and the associated methodologies and PRA models have evolved over the past 35 years. Consequently, the results obtained in the earlier years may be conservative when compared to those obtained using the current methodology and PRA models.

Table 7. Precursors involving failure modes and event initiators that were not explicitly modeled in the PRA or IPE concerning the specific plant at which the precursor event occurred.

Plant	Year	Event Description
Kewaunee	2005	Design deficiency could cause unavailability of safety-related equipment during postulated internal flooding. ***LER 305/05-004***
LaSalle 1 & 2 Crystal River 3	2005	Single-failure vulnerability of 4160 V ESF bus protective relay schemes caused by common power metering circuits. ***LER 302/05-001, LER 373/05-001***
Watts Bar	2005	Component cooling backup line from essential raw cooling water was unavailable because silt blockage. ***IR 390/04-05***
Watts Bar	2005	Low-temperature, over-pressure valve actuations while shut down. ***IR 390/05-03***
Calvert Cliffs 2	2004	Failed relay causes overcooling condition during reactor trip. ***LER 318/04-001***
Palo Verde 1, 2, & 3	2004	Containment sump recirculation potentially inoperable because of pipe voids. ***LER 528/04-009***
Shearon Harris 1	2003	Postulated fire could cause the actuation of certain valves which could result in a loss of the charging pump, RCP seal cooling, loss of RCS inventory, and other conditions. ***LER 400/02-004***
St. Lucie 2	2003	RPV head leakage because of cracking of CRDM nozzles. ***LER 389/03-002***
Crystal River 3 Three Mile Island 1 Surry 1 North Anna 1 & 2	2002	RPV head leakage because of cracking of CRDM nozzle(s). ***LER 302/01-004, LER 289/01-002, LER 280/01-003, LER 339/01-003, LER 339/02-001***
Columbia 2	2002	Common-cause failure of breakers used in four safety-related systems. ***IR 397/02-05***
Davis-Besse	2002	Cracking of CRDM nozzles and RPV head degradation, potential clogging of the emergency sump, and potential degradation of the HPI pumps. ***LER 346/02-002***
Callaway	2002	Potential common-mode failure of all AFW pumps because of foreign material in the CST caused by degradation of the floating bladder. ***LER 483/01-002***
Point Beach 1 & 2	2002	Potential common-mode failure of all auxiliary feedwater (EFW) pumps because of a design deficiency in the EFW pumps' air-operated minimum flow recirculation valves. The valves fail closed on loss of instrument air, which could potentially lead to pump deadhead conditions and a common mode, non-recoverable failure of the EFW pumps. ***LER 266/01-005***
Harris	2002	Potential failure of RHR pump A and containment spray pump A because of debris in the pumps' suction lines. ***LER 400/01-003***
Oconee 1, 2, & 3 Arkansas 1 Palisades	2001	RPV head leakage because of cracking of CRDM nozzle(s). ***LER 269/00-006, LER 269/02-003, LER 269/03-002, LER 270/01-002, LER 270/02-002, LER 287/01-001 , LER 287/01-003, LER 287/03-001, LER 313/01-002, LER 313/02-003, LER 255/01-002, LER 255/01-004***
Kewaunee	2001	Failure to provide a fixed fire suppression system could result in a postulated fire that propagates and causes the loss of control cables in both safe-shutdown trains. ***IR 305/02-06***
Prairie Island 1 & 2	2000	A 1988 change in the backwash system for the cooling water pump drive shaft bearing lubrication water supply system could result in loss of plant cooling water during postulated LOOP conditions. ***LER 282/00-004***

Plant	Year	Event Description
Oconee 1, 2, & 3	2000	Non-seismic 16-inch fire system piping header transited through the auxiliary building and posed a potential flooding problem should the piping rupture during a seismic event. ***IR 269/00-08***
Cook 1 & 2	1999	Postulated high-energy line leaks or breaks in turbine building leading to failure of multiple safety-related equipment. ***LER 315/99-026***
Oconee 1, 2, & 3	1999	Postulated high-energy line leaks or breaks in turbine building leading to failure of safety-related 4 kV switchgear. ***LER 269/99-001***
Cook 2	1998	Postulated high-energy line break in turbine building leading to failure of all CCW pumps. ***LER 316/98-005***
Oconee 1, 2, & 3	1998	Incorrect calibration of the borated water storage tank (BWST) level instruments resulting in a situation where the (EOP requirements for BWST-to-reactor building emergency sump transfer would never have been met; operators would have been working outside the EOP. ***LER 269/98-004***
Haddam Neck	1996	Potentially inadequate RHR pump net positive suction head following a large- or medium-break LOCA because of design errors. ***LER 213/96-016***
LaSalle 1 & 2	1996	Fouling of the cooling water systems because concrete sealant injected into the service water tunnel. ***LER 373/96-007***
Wolf Creek	1996	Reactor trip with the loss of one train of emergency service water because of the formation of frazil ice on the circulating water traveling screens with concurrent unavailability of the turbine-driven AFW pump. ***LER 482/96-001***

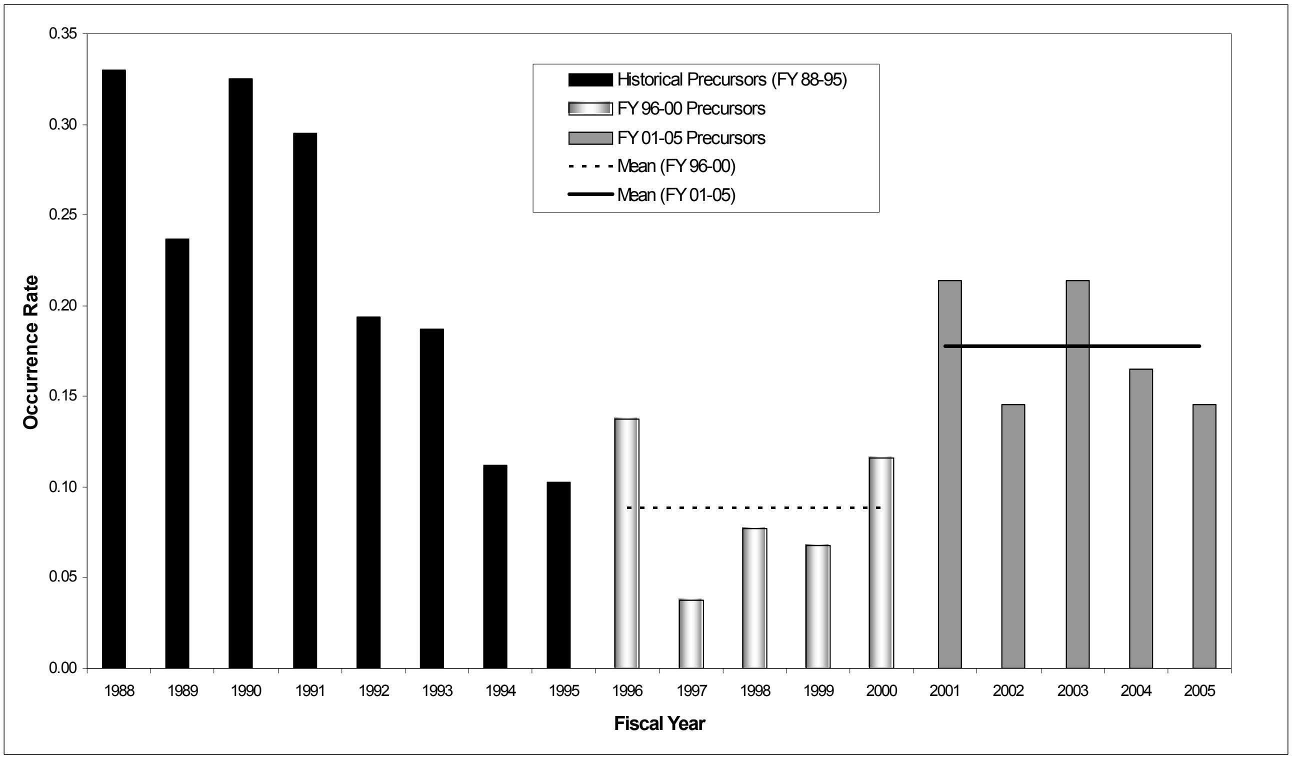

Figure 1: Total Precursors– occurrence rate, by fiscal year. Data for FY 1988 through FY 1995 are shown for historical perspective. Data from FY 2001 through FY 2005 represent the period with an increased ASP scope. No statistically significant trend (p-value = 0.8608) is detected during the FY 2001–2005 period. Data from FY 1996 through 2000 are charted separately since it is part of the data from within the last 10 years without the increase in ASP scope. No statistically significant trend (p-value = 0.3735) is detected during the FY 1996–2000 period.

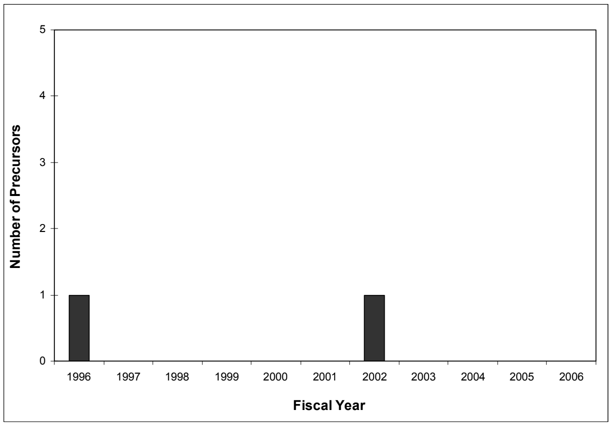

Figure 2: *Significant* precursors (CCDP or ΔCDP ≥10[-3])– number of precursors, by fiscal year. No trend line is shown because no trend is detected that is statistically significant (p-value = 0.4677).

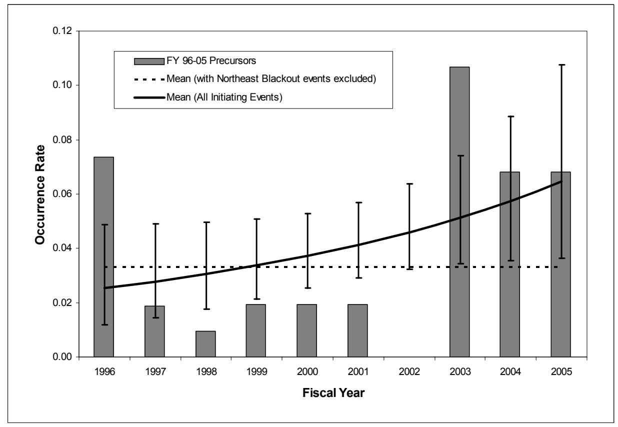

Figure 3: Precursors involving initiating events– occurrence rate, by fiscal year. The increasing trend is statistically significant (0.0489). No statistically significant trend (p-value = 0.3303) is detected when the 2003 Northeast blackout events are excluded.

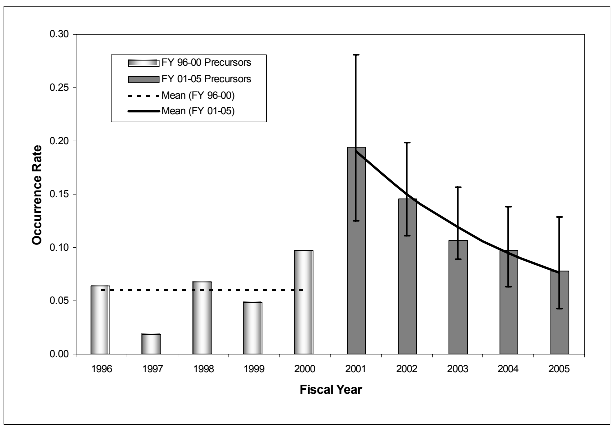

Figure 4: Precursors involving degraded conditions– occurrence rate, by fiscal year. A statistically significant decreasing trend (p-value = 0.0099) is detected during the FY 2001–2005 period of increased ASP scope. No statistically significant trend (p-value = 0.2100) is detected during the period without the increase in ASP scope (FY 1996–2000).

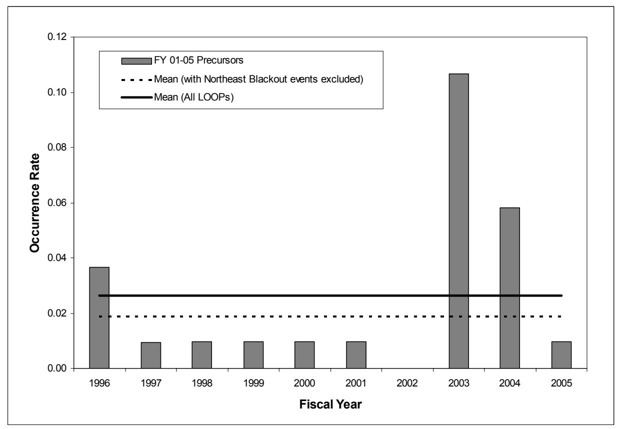

Figure 5: Precursors involving loss of offsite power events– occurrence rate, by fiscal year. No statistically significant trend (p-value = 0.0551) is detected during the FY 1996–2005 period. No statistically significant trend (p-value = 0.5109) is detected when the 2003 Northeast blackout events were excluded.

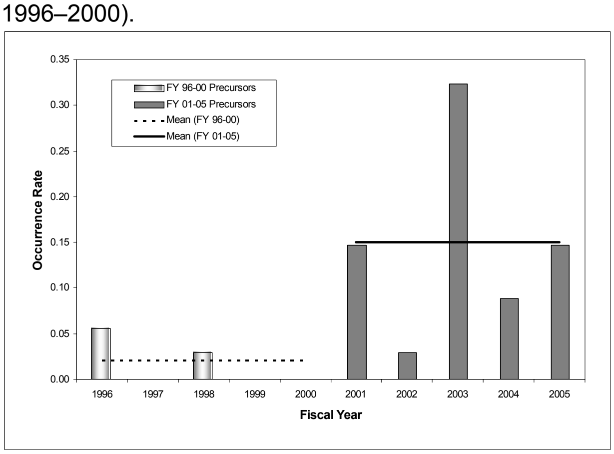

Figure 6: Precursors involving BWRs– occurrence rate, by fiscal year. No statistically significant trend (p-value = 0.0904) is detected during the FY 2001–2005 period of increased ASP scope. No statistically significant increasing trend (p-value = 0.7773) is detected during the period without the increase in ASP scope (FY1996–2000).

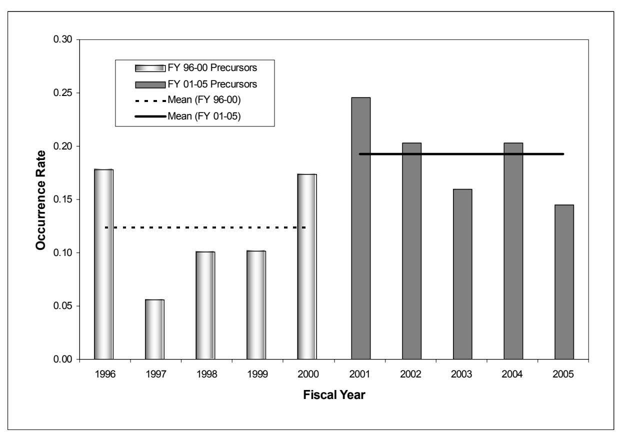

Figure 7: Precursors involving PWRs– occurrence rate, by fiscal year. No statistically significant trend (p-value = 0.8111) is detected during the FY 2001–2005 period of increased ASP scope. No statistically significant trend (p-value = 0.2225) is detected during the period without the increase in ASP scope (FY 1996–2000).

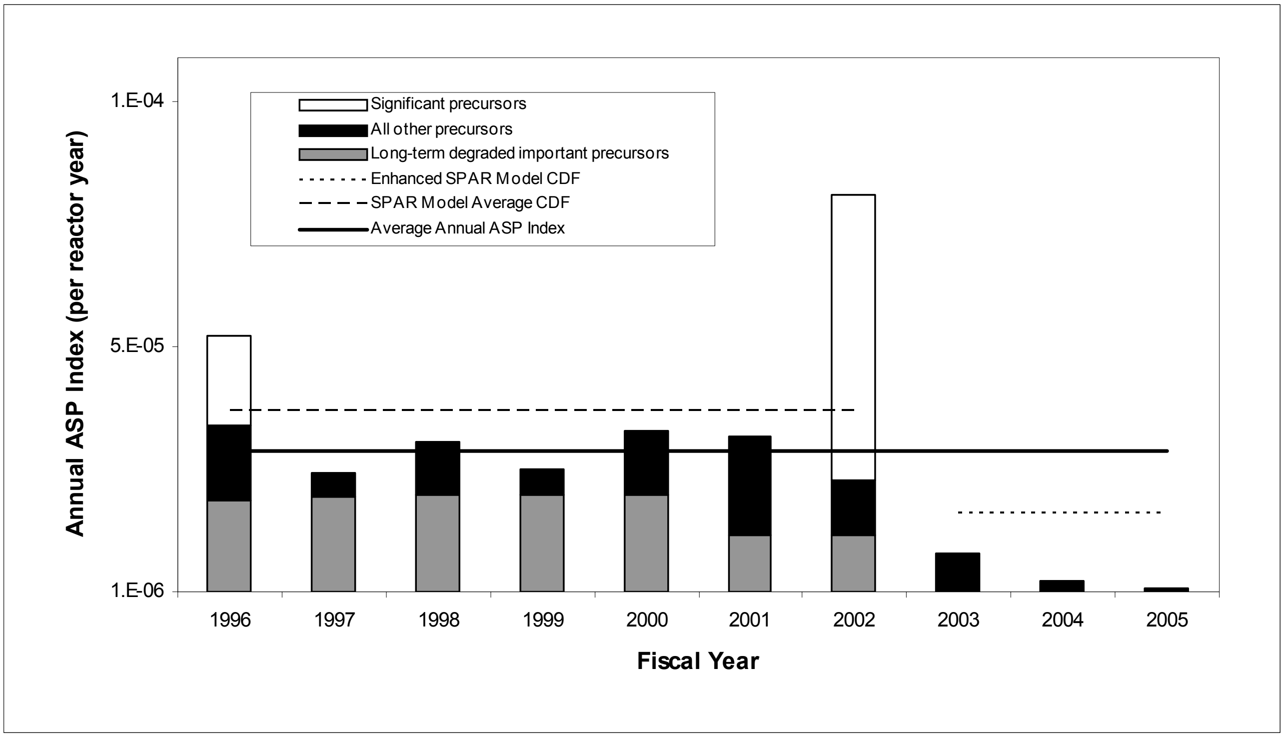

Figure 8: Integrated ASP Index– risk contribution from precursors, per fiscal year. The risk contribution from precursors involving degraded conditions is included in all fiscal years when the degraded condition existed. The risk contribution from precursors involving initiating events is included only in the fiscal year in which the event occurred.

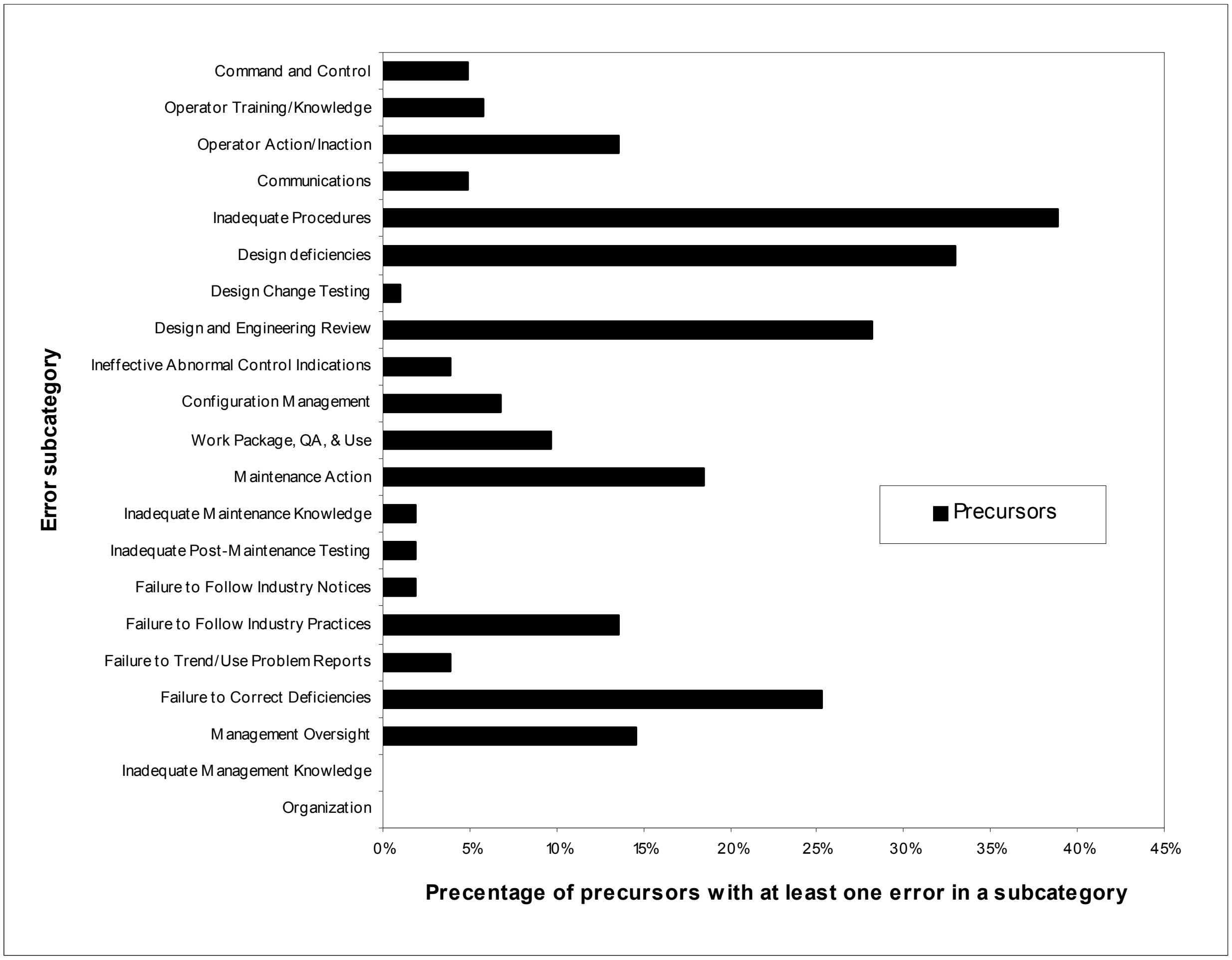

Figure 9: Percentage of precursors with at least one error in an error subcategory.